BC hydro

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Resource Planning

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FINANCIAL EVALUATION GUIDE

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INTRODUCTION

The provincial government and B.C. Hydro are encouraging the efficient development of private sources of electricity by Self-generators (SGs) and independent power producers (IPPs). It is anticipated that private power production achieved through a competitive market will enhance economic and regional development, and lower the cost of electricity in B.C.

B.C. Hydro currently projects that by the end of the decade, up to 5800 GW·h of new electricity could be generated annually in B.C. by SGs and IPPs collectively. It is also possible that many of the large hydroelectric projects identified in the "Electricity Plan 1991 Update" may be available for private sector development.

In order to assess possible opportunities within B.C. Hydro's integrated electric system, proponents should be familiar with B.C. Hydro's estimated cost of new bulk electricity supply (the cost of electricity). This cost is used in the evaluation of private power as follows:

IPP Projects Greater Than 5 MW: IPP proposals compete against all alternatives available to B.C. Hydro to meet future electricity requirements. IPP supply must therefore be provided at a price below both B.C. Hydro's cost of electricity, and the price of competing IPPs.

Small Independent Power: To address the less firm nature of energy from smaller IPPs while maintaining simple, cost-effective procedures, standard prices are offered for electricity from projects of less than 5 MW. These prices are based upon a percentage of the cost of electricity.

Self-generators: For the purpose of understanding revenue flows, SGs can be thought of as IPPs that sell their generated energy at the price negotiated with B.C. Hydro, and then purchase some or all of it back at the customer tariff rate. The net unit price received for the load displacement is therefore the negotiated price for electricity sales, less the tariff for the purchased electricity purchased. As per IPP contracts, the negotiated price must be below the cost of electricity.

This guide outlines the basic principles and application methodology required to estimate B.C. Hydro's cost of electricity. To complete such estimates, the capacity and energy components must be accounted for separately based on the specific characteristics of any given project. The values derived are useful for screening potential projects; they should not be interpreted as the price B.C. Hydro will pay. Contracted prices will vary with market forces (including competing private power offerings), site specific considerations outside the scope of this document, and environmental factors.

The costs presented in this document are **not** applicable to B.C. Hydro's non-integrated areas. Communities outside the power grid are typically powered by small diesel or natural gas generators. Unit costs for these sites are significantly higher than those within the integrated system, are very site specific, and must therefore be reviewed individually.

COMPONENTS OF ELECTRICITY

Electricity can be thought of and valued as the sum of two components: energy, the ability to do work; and capacity, the ability to do the work at the time and rate required.

> An analogy to an automobile can be made wherein gasoline is the energy, the motor represents capacity and the road grade provides the demand. If the only requirement was to drive along level ground at a constant speed, a fractional horsepower engine would suffice and capacity costs would be minimal. If however, it is necessary to occasionally climb steep hills at high speed, a much larger engine is required despite the infrequent use of the additional horsepower. To travel further, more gasoline (energy) is needed.

Energy (kW·h)

Because most of the electricity provided by the B.C. Hydro system comes from hydroelectric sources, the amount of electric energy available fluctuates with variations in precipitation. To ensure load commitments are met, only the amount of energy that has historically been present during the driest sequence of years is considered assured. This assured energy component is said to be firm. B.C. Hydro plans its system to ensure sufficient hydroelectric and other firm energy is available to satisfy firm demand.

During high precipitation years, hydraulic energy may be available that is in excess of B.C. Hydro's firm capability. This additional energy is referred to as secondary energy. It is used to displace thermal generation and/or imports, and is sold to secondary markets (eg. export or interruptible customers). During periods of very high precipitation some water may be spilled from B.C. Hydro's reservoirs, without going through the turbines.

While both firm and secondary energy are valuable to B.C. Hydro, the former is significantly more expensive. The value attached to the latter depends on the incremental value of displacing thermal generation, and the market price for short-term firm and interruptible electrical energy.

Capacity (kW)

Customers generally do not consume energy in a constant, uniform manner. They instead have periods of rapid energy use and others with little or no use. Providing energy at the maximum rate demanded, requires delivery capabilities larger than the average consumption rate, and significantly increases the size and cost of the generation and delivery system.

The concept of capacity costing is therefore derived from the requirement for energy deliveries at high rates on an as-demanded basis. If the rate and timing of electricity deliveries were not critical factors, the separation of capacity costs and energy costs would not be necessary or useful.

COST OF ELECTRICITY

Capacity

The expected cost of new capacity for the next 15 years is presented in Exhibits 1 and 2 on pages 10 and 11 respectively.

In the short term, the cost of serving additional demands for capacity is based on the value of foregone capacity sales in the open market. This is presently estimated at 35 $/kW/yr [All values quoted in this report are in October 1990 $'s] for the Lower Mainland and Vancouver Island. Elsewhere the value of additional capacity is zero in the short-term due to transmission bottlenecks which block access to the market.

The "Electricity Plan 1991 Update" projects that by 1999 new generation capacity will be required. This can most economically be provided by installing additional generators at Mica and Revelstoke Generating Stations. Because very little water is generally spilled over these dams, the additional units would not produce significant amounts of electric energy. The cost of the additional units, estimated at 28 $/kW/yr is therefore fully assignable to capacity. When the cost of transmission is added (See Appendix 2.), the estimated long-term cost of additional capacity supplied to the Lower Mainland becomes 56 $/kW/yr.

The cost of new capacity is projected to increase linearly from the market-based short-term value (35 $/kW/yr) to the cost-based long-term value (56 $/kW/yr).

Firm Energy

In the very short term, the cost of supplying additional firm energy is obtained by reviewing anticipated system operations and spot market prices. B.C. Hydro has estimated the cost in the Lower Mainland over the next four years at 1.8 ¢/kW·h.

For a number of years beyond 1992, small increases in additional demand can be served through increased utilization of existing resources. These opportunities include:

- Increased Burrard Thermal generation
- Resource Smart improvements
- Reduced exports
- Power Smart (energy conservation) initiatives
- Coordination with other utilities
- Increased imports

The cost increases associated with satisfying firm energy demand growth using existing resources can be estimated by using a probabilistic computer model which simulates the demands upon and resources within B.C. Hydro's electric system. Dividing these expected cost increases by the incremental energy provided produces an estimate for the cost of new firm energy in the short run. (See Exhibits 1 and 2.)

> N.B. The estimates provided are only useful for deviations in the projected supply/demand balance of up to 1000 GW·h/yr. Deviations larger than this could significantly change the cost of electricity. For example, if the Self-generation initiative

were to displace an additional 2000 GW·h/yr, the excess supply would drive the cost of electricity (i.e. B.C. Hydro's willingness to pay) down.

As demand continues to grow, it eventually becomes more cost effective to develop new resources than to stretch existing ones. When this occurs the long-term cost of expanding the supply becomes the operative price ceiling.

The Electricity Plan 1991 Update describes several projects on the Peace and Columbia Rivers that might be available to satisfy future demands. The long-term cost of new electricity supply is based on the costs of these projects. Although the in-service dates of a number of these projects extend past the 20 year horizon of the Plan, it is still appropriate to use the cost of these projects to develop the long-term cost of new supply.

To address the uncertainty associated with the timing and sequence for these projects, a weighted average has been taken of their estimated unit cost of firm energy. This average is taken as the expected long-term cost of firm energy.

PROJECT	Unit Cost of Firm Energy (¢/kW·h)	Weighting Factor Based on Firm Energy Production (%)
Peace Site C	5.1	52.3
Keenleyside	5.8	10.9
Murphy	6.3	16.6
Waneta	3.6	10.9
Seven Mile Unit 4	3.2	3.1
Brilliant	5.5	6.2

Weighted Average ≈ 5.3 ¢/kW·h delivered to the Lower Mainland

Electricity

The cost of new electricity supply (See Exhibit 1) is established by summing B.C. Hydro's costs for new firm energy and new capacity (after converting the latter from cost/kW to cost/kW·h using B.C. Hydro's adjusted system capacity factor of 58%). The resulting values are useful for comparisons against fully dispatchable projects with production profiles very similar to that of the B.C. Hydro system (i.e. for additional B.C. Hydro hydroelectric projects).

Private power projects will generally violate one or more of the assumptions underlying the cost of electricity estimates, however, and therefore cannot be directly compared against these values. Cost comparisons should instead be performed using the separate estimates for energy and capacity. (See Appendix 6.)

Secondary Energy

The value of secondary energy is estimated by adding an increment to the simulation study and recording the reductions in operating costs and/or increases in export revenue realized. The results are as follows:

Year	Value (¢/kW·h)
1991	1.2
1992	1.4
1993	1.4
1994	1.4
1995	1.4
1996	1.5

Year	Value (¢/kW·h)
1997	1.5
1998	1.5
1999	1.5
2000	1.5
2001	1.8
2001+	2.2

FACTORS AFFECTING COSTS

Location

While 70% of B.C. Hydro's demands are in the southwest of the province (Lower Mainland and Vancouver Island), generation is largely located in the east and north. Moving the electricity from source to load incurs both energy losses (line and transformation losses), and transmission capacity costs (transformation and transmission equipment). As a result, generation closer to net load areas is more valuable.

Adjustment factors are provided and discussed in Appendix 2. It should be noted that the system voltage losses and wheeling charges are incorporated in the regional costs presented in Exhibit 2. Area transmission and distribution costs (energy losses and capital costs) are not included due to their site specific nature. These potential cost savings should be reviewed on a project by project basis.

Time of Year

B.C. Hydro's demand for electricity is higher during the winter than during the summer, and consequently winter capacity reserves are proportionally reduced. As the probability of meeting commitments decreases, the value of capacity increases. The value of capacity therefore varies significantly over the year. (See Appendix 3.) Energy prices are much less subject to seasonal price variations because energy can usually be inexpensively stored through the retention of water in B.C. Hydro reservoirs.

Monthly Weighting Factors For Capacity

MONTH	FACTOR
January	1.5
February	1.5
March	1.0
April	1.0
May	0.5
June	0.5

MONTH	FACTOR
July	0.5
August	0.5
September	1.0
October	1.0
November	1.5
December	1.5

Time of Day/Week

B.C. Hydro's system is more heavily used between the hours of 7 a.m. and 8 p.m. during week days (excluding holidays). This comprises 270.5 hours (37%) of the 732 hours in an average month. Capacity additions provided outside this period are generally surplus to B.C. Hydro requirements and are therefore of minimal value. Accordingly, the valuation of capacity requires a full review of the expected delivery schedule of a project. (See Appendix 3.)

Because firm energy can usually be inexpensively stored during low load periods for use during periods of higher demand, its value does not vary significantly over the day/week.

Environmental Costs/Benefits

Only direct corporate expenditures related to environmental impacts, such as mitigation programs and pollution control equipment have been included in the estimated costs of energy and capacity provided in this document.

To compensate for costs external to B.C. Hydro, preference is given to projects that have a lower unpriced impact on the environment. Further, the provincial government has announced that private power projects with a positive environmental impact may be eligible for a premium. Environmentally beneficial projects will be evaluated jointly by the Ministries of Energy Mines and Petroleum Resources, and Environment.

Discount Rate

B.C. Hydro, in consultation with the provincial government, presently uses an 8% real discount rate, which reflects the average pre-tax return on public and private investment in the economy. (See Appendix 4 for a discussion of real and nominal dollars and discount rates.) High rates tend to emphasize the large upfront expenditures typical of generating projects and increase the estimated cost of new electricity.

CALCULATING A PROJECT'S POTENTIAL VALUE

Projects vary in start date, term, energy output, capacity output and cash flow and are thus difficult to compare directly. To facilitate comparisons, costs must be "averaged" in a way that captures the time (rental) value of money. The averaging procedure used by B.C. Hydro is called levelizing. (See Appendix 5.)

For convenience, B.C. Hydro has levelized its unit costs for energy and capacity for various start dates and terms. To further simplify analysis, system transmission adjustments have also been included for each of the nine regions within B.C. Hydro's integrated system. The results are provided in the tables in Exhibit 3. These provide B.C. Hydro's cost for various blocks of electricity and are a reference for private power producers.

These tables however, assume a regular and constant production profile from year to year and must not be used for projects with variable annual energy deliveries. Non-uniform blocks must use a year-by-year method to compute the project's worth to B.C. Hydro. (See Appendix 5.)

Depending on the uniformity of the annual output from the plant, one of the following two methods can be used:

Uniform Annual Production

a) Determine from Appendix 2 which B.C. Hydro transmission region the project is in.

b) Select from Exhibit 3 the appropriate levelizing tables for the region.

c) Look up the levelized unit cost of energy and the levelized unit cost of capacity for the project's expected start date and term.

d) Estimate the daily and monthly energy delivery schedules and calculate the effective capacity of the plant as outlined in Appendix 3.

e) Insert the values obtained, in the following equations:

Levelized Total Cost of Electricity =

(Annual Energy Output x Levelized Unit Cost of Energy)

+ (Effective Capacity x Levelized Unit Cost of Capacity)

Levelized Cost/kW·h = (Levelized Total Cost of Electricity)/(Annual Energy Output)

Variable Annual Production

If the project's output is expected to vary from year to year, the levelizing tables provided can not be used, and a more involved, project-specific levelizing procedure is required. (See Appendix 5.) B.C. Hydro staff can assist with this computation if necessary.

The B.C. Hydro levelized unit cost for a similar block of electricity can be compared to the levelized unit cost of the proposed project. Coming in under this price does not guarantee success however, since the IPP must compete with others interested in supplying B.C. Hydro.

PAYMENT SCHEDULES

Independent Power Producers

The levelized unit cost of a project, while useful for evaluating the general attractiveness of a project, may not necessarily represent the most realistic cash flow situation. While IPPs would like to realize their returns up-front to lower the risk of cash flow shortfalls during the early high-debt years, B.C. Hydro would like to spread out the returns to lower the likelihood and impact of premature plant closures. Pricing schedules other than uniform real payments may be considered, where offsetting gains are available.

There are limits to the front-end loading that B.C. Hydro will consider, however, and proponents must support any such request with a sound competitive offering. In general, B.C. Hydro will consider front-end loaded offerings up to that presented by flat nominal payments (i.e. unit prices decline in real terms by the rate of inflation). (See Appendix 7 for further details.)

Regardless of the contracted payment schedule, B.C. Hydro would likely seek compensation from IPPs in the event of premature plant closures.

Self-generators

The cash payment made by B.C. Hydro to SGs will be less per kW·h than that paid to IPPs because different products are being purchased. In the case of an IPP, B.C. Hydro is purchasing additional electricity that it can sell, to at least partially offset the acquisition cost. In the case of a SG, B.C. Hydro is purchasing the ability to redistribute its existing electricity to defer the requirement to expand the electric system. (See Appendix 1.)

SGs can be thought of as IPPs that sell their generated electricity to B.C. Hydro, and then purchase some or all of it back. The net unit price paid by B.C. Hydro for the load displacement provided by the SG is therefore the negotiated price for electricity (as per an IPP contract), less the tariff for electricity purchased from B.C. Hydro. The preferred method of payment to SGs is identical to that for IPPs: payment for production.

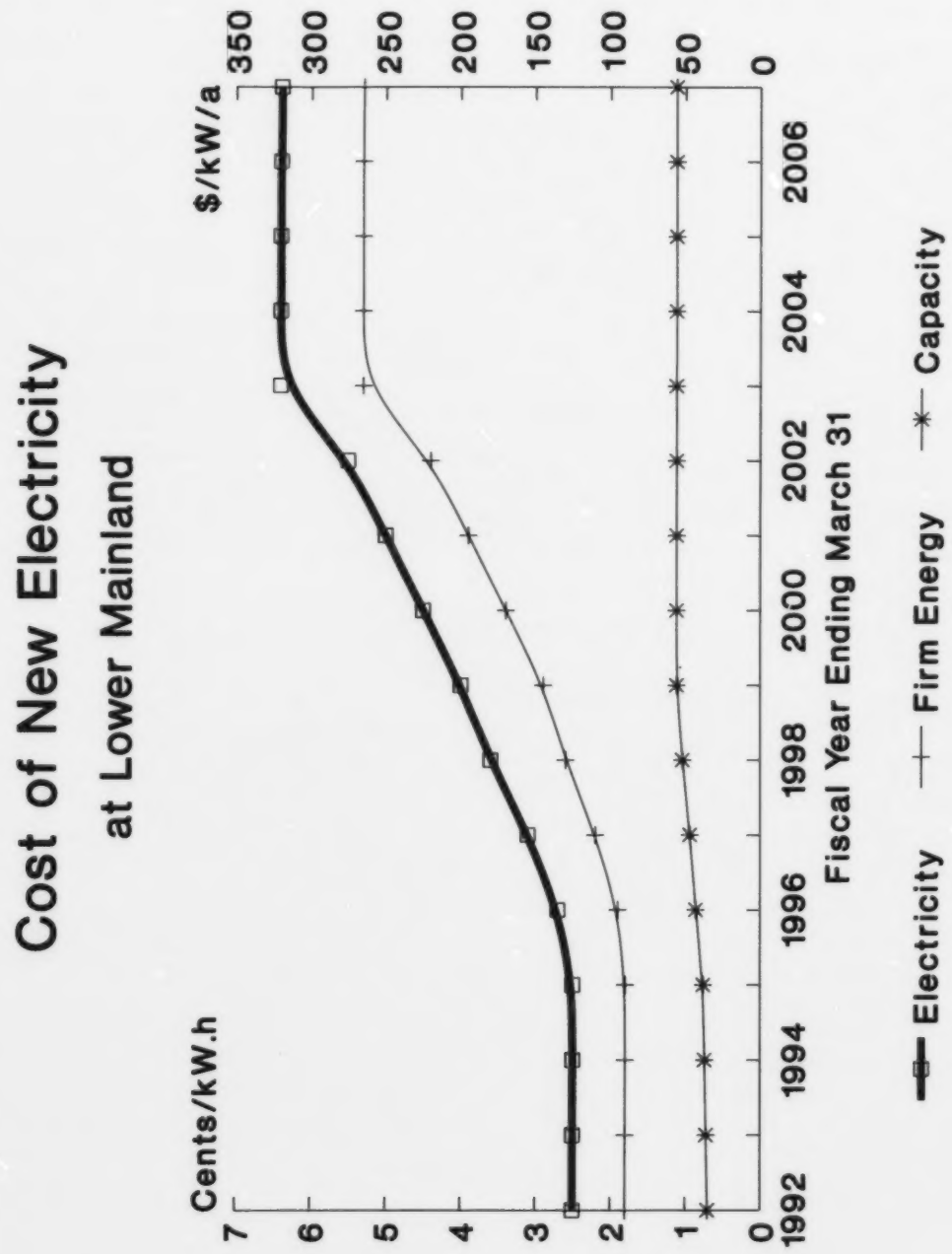
Providing front-end loaded payments to SGs may entail a lower level of risk due to their substantial investment in existing plant and equipment. To the extent that curtailment risk is reduced by the existence of these other assets, B.C. Hydro may consider payment schedules that provide returns to the customer faster than that implicit in the flat nominal payment schedule. Security may be required in such instances; the specific form and value would depend upon the project details.

FURTHER INFORMATION

Power Contracts, a division of B.C. Hydro's Resource Management Strategic Business Unit, was established in 1988 to facilitate the acquisition of competitively priced power from the private sector. It is staffed with experienced engineers that are available to answer questions and concerns on evaluation procedures.

PERSON	AREA of RESPONSIBILITY	PHONE #
Lorne Wells	Manager, Power Contracts	663-3889
John Elliott	Manager, Supply Contracts	663-2019
Jimmy Ko	Small Power and Non-Integrated IPPs	663-2922
Gregg Moe	Self Generation Load Displacement	663-1927
Bill Peterson	Financial Evaluation Engineer	663-2223
Nigel Grant	Domestic IPPs Greater Than 5 MW	663-4392

EXHIBIT 1


Cost of New Electricity
at Lower Mainland
Cents/kW.h
$/kW/a
7
6
5
4
3
2
1
0
350
300
250
200
150
100
50
0
1992
1994
1996
1998
2000
2002
2004
2006
Fiscal Year Ending March 31
Electricity
Firm Energy
Capacity

COST OF NEW FIRM ENERGY AND CAPACITY BY REGION

COST OF NEW FIRM ENERGY (c/kW.h):

	VANC. ISLAND	LOWER MAIN.	K. LAKE NICOLA	SHUSWAP OK.	SELKIRK	EAST KOOT.	CENTRAL INTERIOR	PEACE RIVER	NORTH COAST
91/92	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.7
92/93	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.7
93/94	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.7
94/95	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.7
95/96	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8
96/97	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1
97/98	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.4	2.5
98/99	2.9	2.9	2.8	2.8	2.8	2.8	2.8	2.7	2.8
99/00	3.4	3.4	3.3	3.3	3.3	3.2	3.3	3.2	3.2
00/01	3.9	3.9	3.8	3.8	3.7	3.7	3.7	3.7	3.7
01/02	4.4	4.4	4.3	4.3	4.2	4.2	4.2	4.1	4.2
02/03+	5.3	5.3	5.2	5.1	5.1	5.1	5.1	5.0	5.0

COST OF NEW CAPACITY ($/kW/yr):

91/92	35	35	0	0	0	0	0	0	0
92/93	36	36	0	0	0	0	0	0	0
93/94	37	37	0	0	0	0	0	0	0
94/95	38	38	17	10	3	0	2	0	0
95/96	43	43	21	14	7	0	7	0	0
96/97	49	47	26	19	12	1	11	0	0
97/98	54	52	30	23	16	5	16	1	0
98/99	59	56	34	28	21	10	20	7	1
99/00	59	56	34	28	21	10	20	7	1
00/01	59	56	34	28	21	10	20	7	1
01/02	59	56	34	28	21	10	20	7	1
02/03+	59	56	34	28	21	10	20	7	1
05/06+	91								

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

LEVELIZED COSTS

VANCOUVER ISLAND REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.8	1.8	1.8	1.8	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.8	1.8	1.8	1.8	1.9	2.5	3.1	3.4	3.5	3.6	3.7	3.7	3.7	3.8	3.8
1993/94	1.8	1.8	1.8	1.9	2.0	2.8	3.3	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.1	3.6	3.8	3.9	4.0	4.0	4.1	4.1	4.1	4.1
1995/96	1.9	2.0	2.2	2.4	2.5	3.4	3.8	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3
1996/97	2.2	2.4	2.5	2.7	2.9	3.8	4.1	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5
1997/98	2.6	2.7	2.9	3.2	3.4	4.2	4.4	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7
1998/99	2.9	3.1	3.4	3.6	3.9	4.5	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
1999/00	3.4	3.6	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	3.9	4.1	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	35	35	36	36	38	45	49	55	57	59	60	61	61	62	62
1992/93	36	36	37	38	40	47	52	57	60	62	63	63	64	64	64
1993/94	37	37	39	41	43	50	56	60	63	64	65	66	66	66	67
1994/95	38	41	43	45	48	52	59	63	65	67	68	68	69	69	69
1995/96	43	46	48	51	52	55	63	66	68	70	70	71	71	71	72
1996/97	49	51	54	55	56	59	66	69	71	72	73	73	73	74	74
1997/98	54	56	57	58	58	63	69	72	73	74	75	75	76	76	76
1998/99	59	59	59	59	59	66	72	74	76	76	77	77	77	78	78

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

LOWER MAINLAND REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.8	1.8	1.8	1.8	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.8	1.8	1.8	1.8	1.9	2.5	3.1	3.4	3.5	3.6	3.7	3.7	3.7	3.8	3.8
1993/94	1.8	1.8	1.8	1.9	2.0	2.8	3.3	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.1	3.6	3.8	3.9	4.0	4.0	4.1	4.1	4.1	4.1
1995/96	1.9	2.0	2.2	2.4	2.5	3.4	3.8	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3
1996/97	2.2	2.4	2.5	2.7	2.9	3.8	4.1	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5
1997/98	2.6	2.7	2.9	3.2	3.4	4.2	4.4	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7
1998/99	2.9	3.1	3.4	3.6	3.9	4.5	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
1999/00	3.4	3.6	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	3.9	4.1	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	35	35	36	36	37	44	47	48	48	49	49	49	49	49	50
1992/93	36	36	37	38	40	46	48	49	50	50	50	50	51	51	51
1993/94	37	37	39	41	43	48	50	51	51	51	52	52	52	52	52
1994/95	38	40	42	44	46	50	52	52	53	53	53	53	53	53	53
1995/96	43	45	47	49	50	53	53	54	54	54	54	54	54	54	54
1996/97	47	49	51	53	53	54	55	55	55	55	55	55	55	55	55
1997/98	52	54	55	55	55	56	56	56	56	56	56	56	56	56	56
1998/99+	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

KELLY LAKE / NICOLA REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.8	1.8	1.8	1.8	1.8	2.2	2.8	3.1	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1992/93	1.8	1.8	1.8	1.8	1.8	2.4	3.0	3.3	3.5	3.6	3.6	3.6	3.7	3.7	3.7
1993/94	1.8	1.8	1.8	1.9	2.0	2.7	3.3	3.5	3.6	3.7	3.8	3.8	3.8	3.8	3.9
1994/95	1.8	1.8	1.9	2.1	2.2	3.0	3.5	3.7	3.8	3.9	4.0	4.0	4.0	4.0	4.0
1995/96	1.9	2.0	2.2	2.3	2.5	3.4	3.8	4.0	4.1	4.1	4.2	4.2	4.2	4.2	4.2
1996/97	2.2	2.3	2.5	2.7	2.9	3.7	4.0	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1997/98	2.5	2.7	2.9	3.1	3.3	4.1	4.3	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.6
1998/99	2.8	3.1	3.3	3.5	3.8	4.4	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.8
1999/00	3.3	3.6	3.8	4.1	4.3	4.7	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2000/01	3.8	4.1	4.4	4.6	4.7	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2001/02	4.3	4.7	4.9	4.9	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2002/03+	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	4	7	17	20	22	23	24	24	24	24	25	25
1992/93	0	0	5	9	12	20	23	25	25	26	26	26	27	27	27
1993/94	0	8	12	15	18	24	26	27	28	28	29	29	29	29	29
1994/95	17	19	21	23	25	29	30	30	31	31	31	31	31	31	31
1995/96	21	23	25	27	28	31	32	32	32	32	32	32	32	32	32
1996/97	26	28	30	31	31	32	33	33	33	33	33	33	33	33	33
1997/98	30	32	33	33	33	34	34	34	34	34	34	34	34	34	34
1998/99+	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

SHUSWAP / OKANAGAN REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.8	2.2	2.8	3.1	3.3	3.4	3.4	3.5	3.5	3.5	3.5
1992/93	1.7	1.7	1.7	1.8	1.8	2.4	3.0	3.3	3.4	3.5	3.6	3.6	3.6	3.6	3.7
1993/94	1.7	1.7	1.8	1.9	2.0	2.7	3.2	3.5	3.6	3.7	3.7	3.8	3.8	3.8	3.8
1994/95	1.7	1.8	1.9	2.0	2.2	3.0	3.5	3.7	3.8	3.9	3.9	3.9	4.0	4.0	4.0
1995/96	1.8	2.0	2.1	2.3	2.5	3.3	3.7	3.9	4.0	4.1	4.1	4.1	4.1	4.2	4.2
1996/97	2.1	2.3	2.5	2.7	2.8	3.7	4.0	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.4
1997/98	2.5	2.7	2.9	3.1	3.3	4.0	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5
1998/99	2.8	3.0	3.3	3.5	3.8	4.3	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7
1999/00	3.3	3.5	3.8	4.1	4.2	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.9
2000/01	3.8	4.0	4.4	4.5	4.6	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2001/02	4.3	4.7	4.8	4.9	4.9	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	2	4	12	16	17	18	19	19	19	19	19	19
1992/93	0	0	3	6	8	15	18	19	20	20	21	21	21	21	21
1993/94	0	5	8	10	12	19	20	21	22	22	22	22	23	23	23
1994/95	10	12	14	16	18	22	23	24	24	24	24	24	24	24	25
1995/96	14	16	19	21	22	24	25	25	25	26	26	26	26	26	26
1996/97	19	21	23	24	25	26	26	26	26	27	27	27	27	27	27
1997/98	23	25	26	26	27	27	27	27	27	27	27	27	27	27	27
1998/99+	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

SELKIRK REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.8	3.1	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	3.0	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1993/94	1.7	1.7	1.8	1.8	1.9	2.7	3.2	3.4	3.6	3.6	3.7	3.7	3.7	3.8	3.8
1994/95	1.7	1.8	1.9	2.0	2.1	3.0	3.4	3.6	3.8	3.8	3.9	3.9	3.9	3.9	4.0
1995/96	1.8	2.0	2.1	2.3	2.4	3.3	3.7	3.9	4.0	4.0	4.1	4.1	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.7	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1998/99	2.8	3.0	3.2	3.5	3.7	4.3	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7
1999/00	3.3	3.5	3.7	4.0	4.2	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2000/01	3.7	4.0	4.3	4.5	4.6	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.8	4.8	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	1	2	8	11	12	13	13	14	14	14	14	14
1992/93	0	0	1	2	4	10	13	14	14	15	15	15	15	15	15
1993/94	0	1	3	5	7	13	15	15	16	16	16	16	16	16	17
1994/95	3	5	7	9	11	15	16	17	17	18	18	18	18	18	18
1995/96	7	10	12	14	15	17	18	19	19	19	19	19	19	19	19
1996/97	12	14	16	17	18	19	20	20	20	20	20	20	20	20	20
1997/98	16	19	19	20	20	20	20	21	21	21	21	21	21	21	21
1998/99+	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

EAST KOOTENAY REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.8	3.0	3.2	3.3	3.4	3.4	3.4	3.4	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	3.0	3.2	3.4	3.5	3.5	3.5	3.6	3.6	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.7	3.2	3.4	3.6	3.6	3.7	3.7	3.7	3.7	3.8
1994/95	1.7	1.8	1.9	2.0	2.1	3.0	3.4	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.9
1995/96	1.8	2.0	2.1	2.3	2.4	3.3	3.7	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.6	3.9	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	4.0	4.2	4.3	4.4	4.4	4.4	4.4	4.5	4.5	4.5
1998/99	2.8	3.0	3.2	3.4	3.7	4.3	4.4	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6
1999/00	3.2	3.5	3.7	4.0	4.2	4.5	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8
2000/01	3.7	4.0	4.3	4.5	4.6	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	0	0	3	4	5	6	6	6	6	6	6	6
1992/93	0	0	0	0	0	4	5	6	6	6	7	7	7	7	7
1993/94	0	0	0	0	1	5	6	7	7	7	7	7	7	7	7
1994/95	0	0	0	1	3	6	7	7	8	8	8	8	8	8	8
1995/96	0	0	2	4	5	7	8	8	8	8	8	9	9	9	9
1996/97	1	3	5	6	7	8	9	9	9	9	9	9	9	9	9
1997/98	5	8	9	9	9	10	10	10	10	10	10	10	10	10	10
1998/99+	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

CENTRAL INTERIOR REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.8	3.1	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	3.0	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1993/94	1.7	1.7	1.8	1.8	1.9	2.7	3.2	3.4	3.6	3.6	3.7	3.7	3.7	3.8	3.8
1994/95	1.7	1.8	1.9	2.0	2.1	3.0	3.4	3.6	3.8	3.8	3.9	3.9	3.9	3.9	4.0
1995/96	1.8	2.0	2.1	2.3	2.4	3.3	3.7	3.9	4.0	4.0	4.1	4.1	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.7	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1998/99	2.8	3.0	3.2	3.5	3.7	4.3	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.7
1999/00	3.3	3.5	3.7	4.0	4.2	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2000/01	3.7	4.0	4.3	4.5	4.6	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.8	4.8	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	1	2	8	11	12	13	13	13	13	14	14	14
1992/93	0	0	1	2	4	10	12	13	14	14	14	15	15	15	15
1993/94	0	1	3	5	7	12	14	15	15	16	16	16	16	16	16
1994/95	2	5	7	9	11	15	16	16	17	17	17	17	17	17	17
1995/96	7	9	11	13	14	17	18	18	18	18	18	18	18	18	18
1996/97	11	13	16	17	17	19	19	19	19	19	19	19	19	19	19
1997/98	16	18	19	19	19	20	20	20	20	20	20	20	20	20	20
1998/99+	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

PEACE RIVER REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.3	3.3	3.4	3.4	3.4
1992/93	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.6	3.1	3.4	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1994/95	1.7	1.7	1.8	2.0	2.1	2.9	3.4	3.6	3.7	3.8	3.8	3.8	3.8	3.8	3.9
1995/96	1.8	1.9	2.1	2.2	2.4	3.2	3.6	3.8	3.9	3.9	4.0	4.0	4.0	4.0	4.0
1996/97	2.1	2.2	2.4	2.6	2.8	3.6	3.9	4.0	4.1	4.1	4.2	4.2	4.2	4.2	4.2
1997/98	2.4	2.6	2.8	3.0	3.2	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1998/99	2.7	3.0	3.2	3.4	3.7	4.2	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.6
1999/00	3.2	3.4	3.6	3.9	4.1	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2000/01	3.7	3.9	4.2	4.4	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2001/02	4.1	4.5	4.7	4.7	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2002/03+	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	0	0	2	3	3	4	4	4	4	4	4	4
1992/93	0	0	0	0	0	2	3	4	4	4	4	4	4	4	5
1993/94	0	0	0	0	0	3	4	4	5	5	5	5	5	5	5
1994/95	0	0	0	0	1	4	4	5	5	5	5	5	5	5	5
1995/96	0	0	0	2	3	5	5	5	5	6	6	6	6	6	6
1996/97	0	1	3	4	4	5	6	6	6	6	6	6	6	6	6
1997/98	1	4	5	5	6	6	6	7	7	7	7	7	7	7	7
1998/99+	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

LEVELIZED COSTS

NORTH COAST REGION

NEW FIRM ENERGY (c/kW.h):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.7	3.0	3.2	3.3	3.3	3.4	3.4	3.4	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	2.9	3.2	3.4	3.4	3.5	3.5	3.6	3.6	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.6	3.2	3.4	3.5	3.6	3.7	3.7	3.7	3.7	3.7
1994/95	1.7	1.8	1.9	2.0	2.1	2.9	3.4	3.6	3.7	3.8	3.8	3.9	3.9	3.9	3.9
1995/96	1.8	1.9	2.1	2.2	2.4	3.3	3.7	3.8	3.9	4.0	4.0	4.0	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.6	3.9	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	3.9	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4
1998/99	2.8	3.0	3.2	3.4	3.7	4.2	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6
1999/00	3.2	3.5	3.7	4.0	4.2	4.5	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.8
2000/01	3.7	3.9	4.3	4.4	4.5	4.7	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

NEW CAPACITY ($/kW/yr):

Term (Years)	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1991/92	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1
1992/93	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
1993/94	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
1994/95	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1
1995/96	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1
1996/97	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
1997/98	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1998/99+	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

All values are in October 1990 $'s

Discount rate = 8% net of inflation.

CAUTION: Levelizing tables can be used only if annual production is uniform.

Impact of Self–generation on B.C. Hydro Revenue

(In Comparison to IPPs and B.C. Hydro Generation [BCH])

Demand Increase = 1200 GW.h
Bulk Electricity Rates 3 c/kW.h Note 1
BCH Marginal Cost = 4.5 c/kW.h Note 2

Source	Unit Costs			BCH Initial Sales (GW.h)	BCH Sales Increase (GW.h)	BCH Final Sales (GW.h)	Increase In BCH Costs (000's)	Increase In Revenue (000's)	Increase In Income (000's)
	BCH c/kW.h	Private c/kW.h	Total c/kW.h						
BCH	4.5	0	4.5	40000	1200	41200	$54,000	$36,000	($18,000)
IPP	4	0	4	40000	1200	41200	$48,000	$36,000	($12,000)
	4.5	0	4.5	40000	1200	41200	$54,000	$36,000	($18,000)
	5	0	5	40000	1200	41200	$60,000	$36,000	($24,000)
Self Gen.	0.5	2.5	3	40000	0	40000	$6,000	$0	($6,000)
	1	3.5	4.5	40000	0	40000	$12,000	$0	($12,000)
	1.5	3	4.5	40000	0	40000	$18,000	$0	($18,000)
	2	2.5	4.5	40000	0	40000	$24,000	$0	($24,000)
	2	3	5	40000	0	40000	$24,000	$0	($24,000)
	2.5	3	5.5	40000	0	40000	$30,000	$0	($30,000)

Shaded options are at least as attractive to B.C. Hydro, as its own generation is.

Note 1: Electricity freed by SGs or acquired from IPPs or B.C. Hydro generation is assumed to be sold at the average bulk electricity rate (as opposed to BCH's average revenue rate). The costs and revenues associated with distributing the electricity have been ignored since they should sum to zero, and have no effect upon net income.

Note 2: Levelized marginal cost for 25 year term starting in 92/93, in Lower Mainland.

Appendix 2

Cost Adjustments for Location

Energy

Energy losses are incurred as a result of transporting electricity from generator to load. The magnitude of the losses varies with:

- Distance transported
- Current carried
- Conductor size
- Extent of voltage transformation required

Average loss factors have been computed for the 9 major transmission regions within B.C. Hydro's system. These are presented in Figure 1 of this appendix, and can be used as follows:

Total Value at Generation = Total Value at Load

$C_{Generation} \times Q_{Generation} = C_{Load} \times Q_{Load}$ Where: C = Unit Cost of Energy
Q = Quantity

But: $Q_{Load} = Q_{Generation} \times (1 - \text{Loss Factor})$

Therefore: $C_{Generation} = C_{Load} \times (1 - \text{Loss Factor})$

Example: If the cost of energy in the Lower Mainland = 5.3 ¢/kW·h, what is it in the Peace River Region?

From Figure 1, the Loss Factor = 6%

Cost of energy at Peace River = 5.3 x (1 - 0.06) = 5.0 ¢/kW·h

This agrees with the value presented in Exhibit 2.

Capacity

The most attractive option for increasing B.C. Hydro's capacity is the addition of generators at Mica and Revelstoke. To employ this capacity outside the Shuswap/Okanagan region, it must be transported through the 500 kV system. The allocated costs of doing so are presented in Figure 2 of this appendix. They can be used as follows:

$$\text{Capacity Cost}_{Load} = \frac{\text{(Generation Cost + Transmission Cost)}}{\text{(1 - Loss Factor)}}$$

Where: Generation Cost = 27.6 $/kW/yr
Transmission Cost = Sum of wheeling costs from Shuswap/Okanagan to load.
Loss Factor = % loss from Shuswap/Okanagan to load.

Example: What is the long-term cost of capacity in the Lower Mainland?

Generation Cost = 27.6 $/kW/yr

$\text{Transmission Cost}_{\text{Shuswap/Okanagan to Kelly Lake/Nicola}}$ = 6.3 $/kW/yr

$\text{Transmission Cost}_{\text{Kelly Lake/Nicola to Lower Mainland}}$ = 20.7 $/kW/yr

$\text{Loss Factor}_{\text{Shuswap/Okanagan to Lower Mainland}}$ = 3%

$\text{Cost of Capacity}_{\text{Lower Mainland}} = (27.6 + 6.3 + 20.7)/(1 - 0.03) = 56.3$ $/kW/yr

This agrees with the (rounded) value presented in Exhibit 2.

Example: Express the long-term cost of capacity in the Lower Mainland (56 $/kW/yr) in terms of ¢/kW·h to allow its addition to the cost of firm energy, to produce the cost of electricity estimate.

The cost of capacity in $/kW is converted to ¢/kW·h using B.C. Hydro's system capacity factor of 65% adjusted for the required reserve margin of 12%, or 58%. On average 1 kW of installed capacity in the B.C. Hydro system produces:

1 kW x 58% x 8760 h/yr = 5080 kW·h/yr

The absolute value of the resource does not change as a result of changing units, therefore:

$V_1 = C_1 \times Q_1 = V_2 = C_2 \times Q_2$

Where C_1 = Cost expressed in $/kW
Q_1 = Quantity in kW
C_2 = Cost expressed in $/kW·h
Q_2 = Equivalent quantity in kW·h

$$C_2 = \frac{C_1 \times Q_1}{Q_2} = \frac{56 \text{ \$/kW/yr} \times 1 \text{ kW} \times 100 \text{ ¢/\$}}{5080 \text{ kW·h/yr}} = 1.1 \text{ ¢/kW·h}$$

Electricity

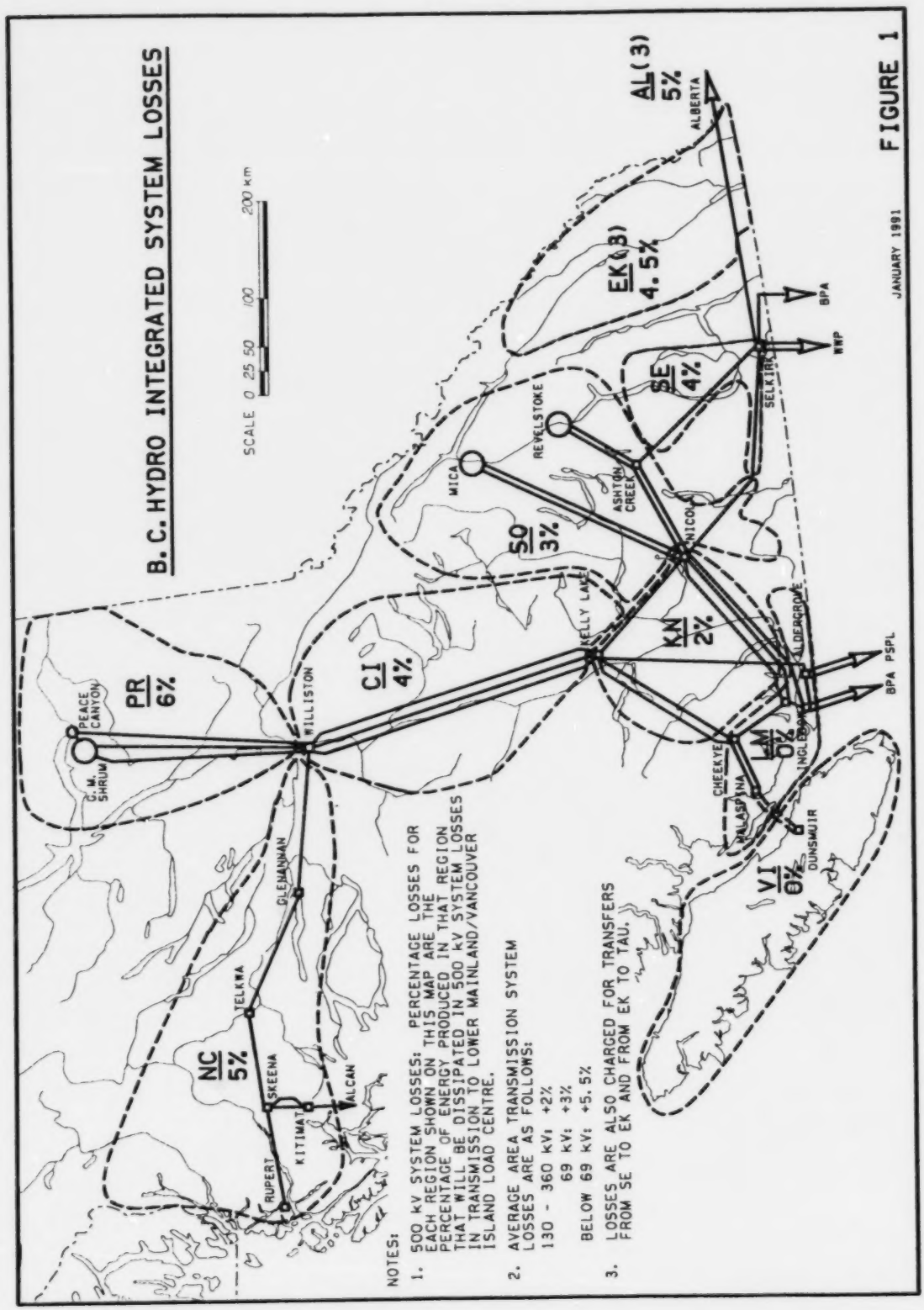
The impact of location upon the cost of electricity is determined by computing energy and capacity separately, and summing.

Example: What is the long-term cost of electricity in the Lower Mainland?

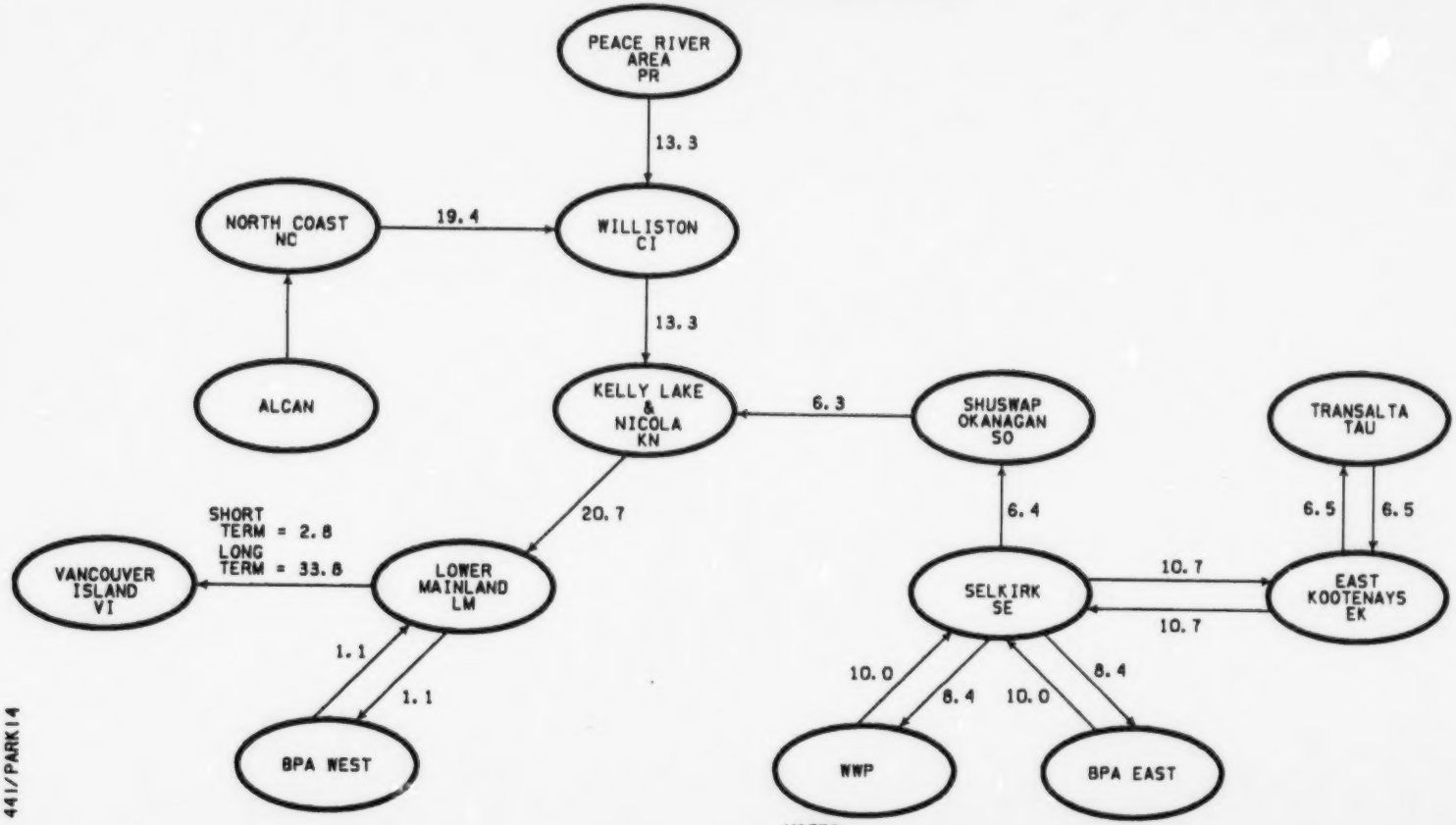
$\text{Electricity}_{LM} = \text{Energy}_{LM} + \text{Capacity}_{LM}$

= 5.3 ¢/kW·h + 1.1 ¢/kW·h = 6.4 ¢/kW·h

Figure 1


B.C. HYDRO INTEGRATED SYSTEM LOSSES
SCALE 0 25 50 100 200 km
NC 5%
PR 6%
CI 4%
SO 3%
KN 2%
LM 0%
VI 0%
SE 4%
EK(3) 4.5%
AL(3) 5%
PEACE CANYON
G.M. SHRUM
WILLISTON
TELKWA
GLENANNAN
SKEENA
KITIMAT
ALCAN
RUPERT
MICA
REVELSTOKE
ASHTON CREEK
NICOLA
KELLY LAKE
SELKIRK
ALBERTA
BPA
WNP
BPA PSPL
CHEEKYE
NANAIMO
DUNSMUIR
JANUARY 1991
FIGURE 1
NOTES:
1. 500 KV SYSTEM LOSSES; PERCENTAGE LOSSES FOR EACH REGION SHOWN ON THIS MAP ARE THE PERCENTAGE OF ENERGY PRODUCED IN THAT REGION THAT WILL BE DISSIPATED IN 500 KV SYSTEM LOSSES IN TRANSMISSION TO LOWER MAINLAND/VANCOUVER ISLAND LOAD CENTRE.
2. AVERAGE AREA TRANSMISSION SYSTEM LOSSES ARE AS FOLLOWS:
130 - 360 KV: +2%
69 KV: +3%
BELOW 69 KV: +5.5%
3. LOSSES ARE ALSO CHARGED FOR TRANSFERS FROM SE TO EK AND FROM EK TO TAU.

B. C. HYDRO INTEGRATED SYSTEM
INTERREGIONAL AND INTERTIE FIRM WHEELING COSTS
(IN $/kW/YR)



NOTES:

1. REFLECTS 1991/92 SYSTEM PLAN
2. IN 1990 $'S

441/PARK14

Figure 2

Appendix 3

Calculating a Project's Effective Capacity

The separation of energy and capacity charges is important when energy is demanded at a varying rate. It is the existence of peaks and valleys in the demand profile that gives rise to the notion of capacity costs. It is not surprising, therefore, that the effective capacity provided by a project depends upon its degree of flexibility to serve B.C. Hydro's load patterns:

1) Daily Peaking: On non-holiday weekdays, B.C. Hydro's load begins increasing at approximately 7 a.m. as residential, commercial and, to a leaser extent, industrial activity increases. It remains comparatively high until approximately 8 p.m., by which time most electricity intensive commercial and residential activity is complete. During all other times, demand is significantly lower. Of the 732 hours in an average month, 270.5 (37%) are heavy load hours, and 461.5 (63%) are light load hours.

   During light load hours, B.C. Hydro has surplus capacity. Additional capacity provided during this time has minimal value. Only the additional capacity provided during heavy load hours is valuable to B.C. Hydro. Effective capacity can therefore be defined by:

   $$\text{Effective Capacity} = \text{Capacity}_{\text{Heavy Load Hours}} = \frac{\text{Energy Delivered During Heavy Load Hours}}{\text{Number of Heavy Load Hours}}$$

   Example: A project with a maximum continuous rating of 25 MW is expected to deliver 11,000 MW·h of energy monthly. It is possible to run the plant such that 5950 MW·h of its energy production will be delivered during the heavy load hours. What is the effective capacity of the plant?

   $$\text{Capacity}_{\text{Heavy Load Hours}} = 5950 \text{ MW·h}/270.5 \text{ Hours} = 22 \text{ MW}$$

   By comparison, the Average Capacity = 11,000 MW·h/732 Hours = 15 MW

2) Seasonal Peaking: B.C. Hydro's capacity reserve is smaller in the winter months because demand for electricity is high, reservoir levels are low (which reduces head), and some projects have reduced inflows (which decreases their ability to serve heavy peak loads). To encourage capacity deliveries in the critical winter months, weighting factors are applied to the effective monthly capacity values. While the factors average to one over the year, they emphasize capacity deliveries during low capacity reserve periods, and downplay capacity deliveries during high reserve periods.

Example 1: Favourable Seasonal Capacity Profile

	Monthly Weighting	Capacity $_{\text{Heavy Load Hours}}$ For the Month	Weighted Capacity
January	1.5	22	33
February	1.5	20	30
March	1	15	15
April	1	11	11
May	0.5	8	4
June	0.5	10	5
July	0.5	12	6
August	0.5	14	7
September	1	19	19
October	1	15	15
November	1.5	16	24
December	1.5	18	27
	Total	180	196
	Monthly Average	15 MW	**16.3 MW**

Example 2: Unfavourable Seasonal Capacity Profile

	Monthly Weighting	Capacity $_{\text{Heavy Load Hours}}$ For the Month	Weighted Capacity
January	1.5	8	12
February	1.5	10	15
March	1	13	13
April	1	15	15
May	0.5	22	11
June	0.5	20	10
July	0.5	22	11
August	0.5	20	10
September	1	17	17
October	1	15	15
November	1.5	8	12
December	1.5	10	15
	Total	180	156
	Monthly Average	15 MW	**13 MW**

Note: The weighted capacity is useful only for assigning a value to a plant's capacity products; it is not an indicator of capacity available to address customer demands. Capacity $_{\text{Heavy Load Hours}}$ addresses this requirement.

Example 3: Constant Seasonal Capacity Profile

	Monthly Weighting	Capacity Heavy Load Hours For the Month	Weighted Capacity
January	1.5	15	22.5
February	1.5	15	22.5
March	1	15	15
April	1	15	15
May	0.5	15	7.5
June	0.5	15	7.5
July	0.5	15	7.5
August	0.5	15	7.5
September	1	15	15
October	1	15	15
November	1.5	15	22.5
December	1.5	15	22.5
	Total	180	180
	Monthly Average	15 MW	**15 MW**

Example 4: Variable but Neutral Seasonal Capacity Profile

	Monthly Weighting	Capacity Heavy Load Hours For the Month	Weighted Capacity
January	1.5	10	15
February	1.5	12	18
March	1	14	14
April	1	16	16
May	0.5	18	9
June	0.5	20	10
July	0.5	10	5
August	0.5	12	6
September	1	14	14
October	1	16	16
November	1.5	18	27
December	1.5	20	30
	Total	180	180
	Monthly Average	15 MW	**15 MW**

Appendix 4

Real Versus Nominal Dollars and Discount Rates

There are two potential components to the time value of money:

1) Rental Charges: As with virtually all other resources, owners of capital want to be compensated for lending their goods. Since both the rented good and the payment are in the form of dollars, the rental rate is usually expressed in percent format. Another name for this rental rate is the "real" discount (or interest) rate, presumably since it reflects the real value of the resource being exchanged.

2) Devaluation Adjustment: In an environment of price inflation, capital depreciates over time. To compensate the owner for this loss of value, an inflation fee is charged in addition to the rental fee.

Total Charge = Rental Charge + Devaluation Adjustment on Capital and Rental

$= C \cdot r + C \cdot i + C \cdot r \cdot i$
$= C \cdot (r + i + r \cdot i)$
$= C \cdot (r + i + r \cdot i + 1 - 1)$
$= C \cdot [(1+r) \cdot (1+i) - 1]$

where r = rental rate (%)
i = inflation rate (%)
C = Capital
$[(1+r) \cdot (1+i) - 1]$ = nominal discount rate

There are two choices for performing financial evaluations:

1) Deal with the world as it comes (i.e. complete with inflation) and discount the dollars of the day (i.e. nominal dollars) using the nominal discount rate, or;

2) Transform the world into one with zero inflation (i.e. by adjusting prices by an appropriate price index) and discount the adjusted dollars using the real discount rate. Dollars adjusted to remove inflation are said to be real, constant or net (of inflation) dollars.

In this document the latter approach has been adopted; inflation has been removed by carrying prices in terms of constant 1990 dollars. This permits the same discount rate to be applied to both monetary and nonmonetary goods, and removes the distortion introduced by inflation. B.C. Hydro uses a discount rate of 8% real, and typically assumes an inflation rate of 4.5%. The computed nominal rate is therefore 12.9% [1.08 x 1.045 - 1 = 0.1286].

Readers are reminded to exercise care to ensure the appropriate dollars are employed throughout their analyses. If nominal and real dollars/discount rates are interchanged, inaccurate computations will result.

Appendix 5

Levelizing

Because electricity supply proposals come in many different configurations of energy output, capital cost, operating cost, location, start date and term, they are often difficult to compare. To address this difficulty, B.C. Hydro has adopted a method of standardizing costs so comparisons can be made. This mathematical manipulation is called levelizing.

Levelizing involves the conversion of non-uniform cost and energy streams, into a present-value-equivalent uniform unit cost series. In simpler terms, it is a method of obtaining an "average" unit cost that incorporates the rental value of the resource. There are two methods of doing this:

1) Spread both costs and electricity evenly over the term of the contract (accounting for the time value of the resource), and divide the former by the latter to produce an "average" unit cost. This approach does not require the discounting or amortizing of energy when annual energy output is uniform, and thus is often preferred.

   [Just as for dollars, energy can be discounted to reflect its time (rental) value. This is analogous to selling the energy at some future date, discounting the dollars obtained, and expressing the discounted dollar value in terms of kW·h that could be purchased.]

2) Convert both total cost and total electricity production streams into values at a single point in time, and divide. Since this method by definition requires the discounting of energy, it is often overlooked in favour of method 1 above. Where nonuniform energy streams are encountered, however, energy discounting is required and method 2 provides the most direct results.

Example: Assume a project produces a constant 10 kW·h per year over its 10 year life, while incurring costs (in constant 1990 dollars, at the end of each year) as below. Also assume a discount rate of 8% real (net of inflation).

Year:	1	2	3	4	5	6	7	8	9	10
Cost:	18¢	18	19	22	26	29	34	39	44	53
Energy:	10	10	10	10	10	10	10	10	10	10
Unit Cost:	1.8	1.8	1.9	2.2	2.6	2.9	3.4	3.9	4.4	5.3

Method 1: Because the energy production is uniform, we can avoid the discounting of energy.

PV (Costs) = $18/(1+.08)^1 + 18/(1+.08)^2 + 19/(1+.08)^3 + 22/(1+.08)^4 + \ldots + 53/(1+.08)^{10}$ = 187¢

Annual "average" cost = 27.9¢ (187¢ amortized at 8% over 10 years = 27.9¢)

Levelized Unit Cost = (27.9¢)/(10 kW·h) = 2.79 ¢/kW·h

Method 2: This procedure substitutes calculating the PV of the energy, in place of amortizing the PV of the costs.

$$PV\ (Energy) = 10/(1+.08)^{1} + 10/(1+.08)^{2} + 10/(1+.08)^{3} + 10/(1+.08)^{4} + \ldots\ldots + 10/(1+.08)^{10} = 67.1\ kW{\cdot}h$$

PV (Costs) = 187¢ as per Method 1.

The levelized unit cost = 187¢/(67.1 kW·h) = 2.79 ¢/kW·h as in Method 1.

B.C. Hydro's cost data have been levelized to facilitate project comparisons. The above example uses data from the Lower Mainland region, for a ten year block of firm energy beginning in 1993/94. A review of the table in Exhibit 3 confirms the levelized unit cost of 2.79¢ (shown as 2.8 due to rounding) derived above.

Example: Consider a project with an irregular energy production profile (Power Smart projects typically have such a profile). Assume a project produces 10 kW·h the first year, and increases production by 10 kW·h per year over its 10 year life. It incurs unit costs (in constant 1990 dollars, at the end of each year) as per the previous example. Again, assume an 8% real discount rate.

Year:	1	2	3	4	5	6	7	8	9	10
Energy:	10	20	30	40	50	60	70	80	90	100
Unit Cost:	1.8¢	1.8	1.9	2.2	2.6	2.9	3.4	3.9	4.4	5.3
Total Cost:	18¢	36	57	88	130	174	238	312	396	530

Method 1: Since the energy production is not uniform, we must now "average" both the energy production and the project costs.

$$PV\ (Costs) = 18/(1+.08)^{1} + 36/(1+.08)^{2} + 57/(1+.08)^{3} + 88/(1+.08)^{4} + \ldots\ldots + 530/(1+.08)^{10} = 1107¢$$

Annual "average" cost = 165¢ (1107¢ amortized at 8% over 10 years = 165¢)

$$PV\ (Energy) = 10/(1+.08)^{1} + 20/(1+.08)^{2} + 30/(1+.08)^{3} + 40/(1+.08)^{4} + \ldots\ldots + 100/(1+.08)^{10} = 327\ kW{\cdot}h$$

Annual "average" energy = 48.7 kW·h (327 amortized at 8% over 10 years = 48.7)

Levelized unit cost = 165¢/(48.7 kW·h) = 3.39 ¢/kW·h

Method 2: As above, PV (Costs) = 1107¢; PV (Energy) = 327 kW·h

Levelized unit cost = [PV (Costs)]/[PV (Energy)] = 3.39 ¢/kW·h

While both methods produce the same result, method 2 avoids the redundant amortizing of the present values and discourages shortcuts which can lead to the neglect of irregular energy production influences.

Appendix 6

Example: Comparing an IPPs Costs to B.C. Hydro's

Location: Lower Mainland
Capacity: 20 MW nominal; 16.3 MW effective (as per "Favourable Seasonal Capacity Profile [Example 1, Appendix 3]).
Annual Output: 131.4 GW·h (15 average MW)
Expenditures: As below (in October 1990 $'s, at end of fiscal year specified).
Salvage Value: None.
In Service Date: April 1, 1993.

Year	Capital Costs ('000's)	Operating Costs ('000's)	PV (Costs) at Start-up ('000's)	PV (Energy) at Start-up (GW·h)
1991/92	$10,000		$10,000 x 1.08^{1}	
1992/93	12,560		12,560	
1993/94		$2000	$2000/1.08^{1}$	$131.4/1.08^{1}$
1994/95		1500	$1500/1.08^{2}$	$131.4/1.08^{2}$
1995/96		1000	$1000/1.08^{3}$	$131.4/1.08^{3}$
1996/97		800	$800/1.08^{4}$	$131.4/1.08^{4}$
1997/98		1000	$1000/1.08^{5}$	$131.4/1.08^{5}$
1998/99		1000	$1000/1.08^{6}$	$131.4/1.08^{6}$
1999/00		1200	$1200/1.08^{7}$	$131.4/1.08^{7}$
2000/01		1200	$1200/1.08^{8}$	$131.4/1.08^{8}$
2001/02		1200	$1200/1.08^{9}$	$131.4/1.08^{9}$
2002/03		1300	$1300/1.08^{10}$	$131.4/1.08^{10}$
TOTALS	$22,560	$12,200	$31,741.4	881.7 GW·h

1) Calculate Project's Levelized Unit Cost

Method 1: $31,741,400 amortized over 10 years at 8% = $4,730,400

Levelized unit cost = ($4,730,400 x 100¢/$)/131,400,000 kW·h = 3.6 ¢/kW·h

Method 2: Levelized unit cost = ($31,741,400 x 100¢/$)/881,705,000 kW·h = 3.6 ¢/kW·h

2) Calculate B.C. Hydro's Levelized Unit Cost for Equivalent Energy and Capacity

a) Since the project's energy delivery is uniform, the levelizing tables in Exhibit 3 can be used (irregular energy production would require the procedure outlined in Appendix 5, Example 2):

Levelized cost of energy for Lower Mainland starting 1993/94 for 10 years = 2.8 ¢/kW·h
Levelized cost of capacity for Lower Mainland starting 1993/94 for 10 years = 48 $/kW

b) Effective capacity = 16.3 MW as per Appendix 2, Example 1.

c) Levelized Total Cost = (Annual Energy Output x Levelized Unit Cost of Energy)
+ (Effective Capacity x Levelized Unit Cost of Capacity)

= (131,400,000 x 2.8/100) + (16,300 x 48) = $4,461,600

Levelized Unit Cost = 4,461,600/131,400,000 x 100 = 3.40 ¢/kW·h

Since B.C. Hydro's internal cost (3.4 ¢/kW·h) is less than the project's cost (3.6 ¢/kW·h) for the same product, the project is unattractive (barring unpriced environmental impacts). This result can be changed, however, by delaying the project for a year, or extending its term to 15 years (while holding all project costs constant).

1) The project's levelized costs remain at or below 3.6 ¢/kW·h.
2) B.C. Hydro's levelized unit costs become:

For a one year delay:

Levelized cost of energy for Lower Mainland starting 1994/95 for 10 years = 3.1 ¢/kW·h
Levelized cost of capacity for Lower Mainland starting 1994/95 for 10 years = 50 $/kW

Levelized Total Cost = (131,400,000 x 3.1/100) + (16,300 x 50) = $4,888,400

Levelized Unit Cost = 4,888,400/131,400,000 x 100 = 3.72 ¢/kW·h

For a five year extension:

Levelized cost of energy for Lower Mainland starting 1993/94 for 15 years = 3.3 ¢/kW·h
Levelized cost of capacity for Lower Mainland starting 1993/94 for 15 years = 50 $/kW

Levelized Total Cost = (131,400,000 x 3.3/100) + (16,300 x 50) = $5,151,200

Levelized Unit Cost = 5,151,200/131,400,000 x 100 = 3.92 ¢/kW·h

Both these actions result in increases to B.C. Hydro's levelized unit cost such that the private power is less expensive. It may therefore be possible to negotiate a contract, subject to competitive market forces.

Appendix 7

Front-end Loading

As presented on the following page, very different cash flow streams can be formulated which have identical present values (PVs). For example a PV of $1000 can be obtained from:

- a ten year stream of nominal dollar payments of $183.26 each. (A flat, nominal schedule.)
- a ten year stream of real dollar payments of $149.03 each. (A levelized schedule.)
- a ten year stream of nominal dollar payments starting at $250, and decreasing by $18.93 per year. (A front-end loaded schedule.)
- a ten year stream of nominal dollar payments starting at $100, and increasing by $23.62 per year. (A delayed payment schedule.)

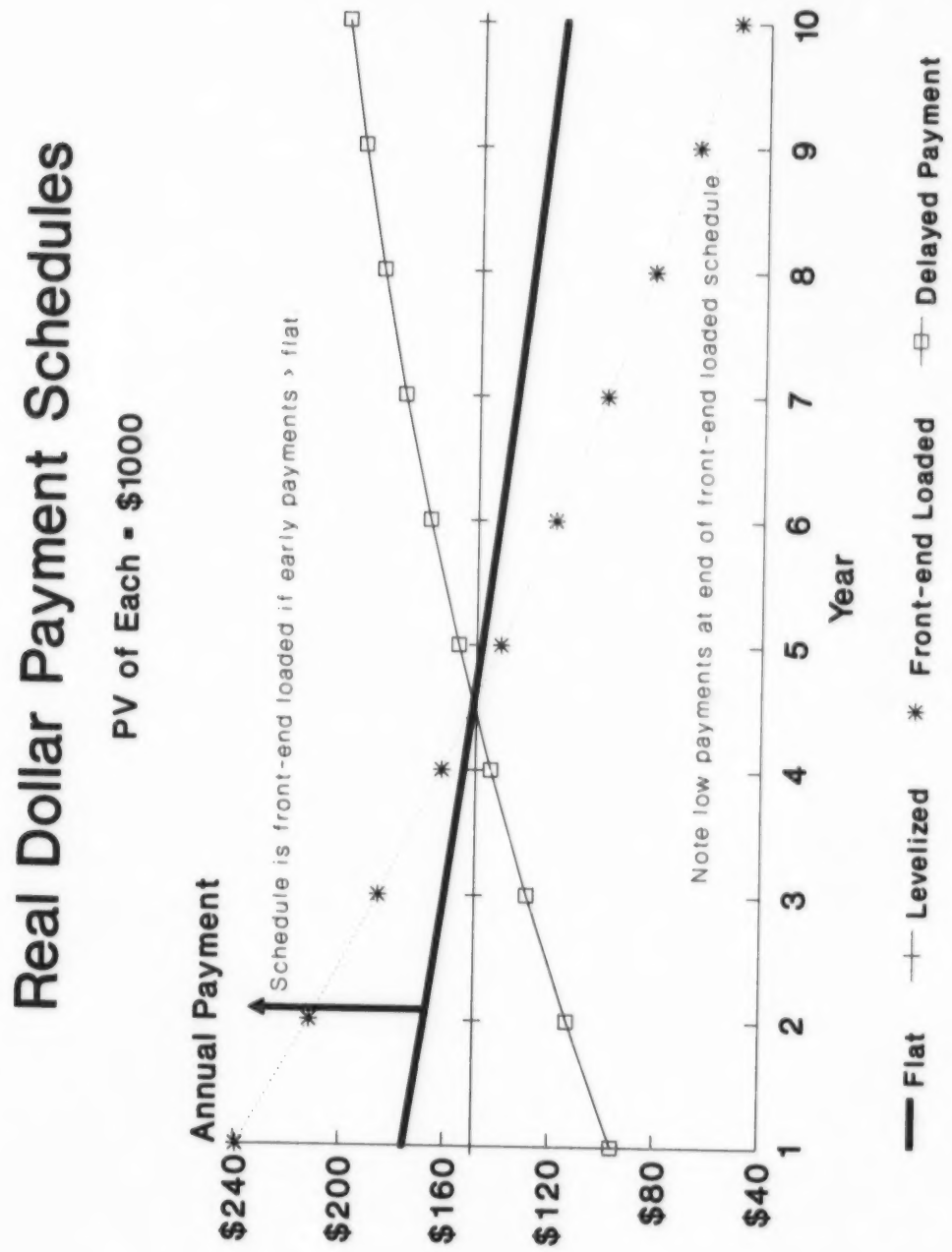
In fact, an infinite number of permutations are possible which provide the same $1000 PV. These can be presented in either real dollar or nominal dollar form by excluding/including inflation.

In the absence of risk, B.C. Hydro would be indifferent to the cash flow schedule employed so long as the PV was constant. Risk is always present, however, and as such the payment schedule must be considered.

When a contract is front-end loaded, the payments in the latter years are smaller than the average payment under the contract. (This is a mathematical necessity to maintain the same PV.) These smaller payments, however, may not provide sufficient motivation to ensure the project is operated for the entire term of the contract. Since in the majority of contracts B.C. Hydro is relying upon the avoided cost savings from the latter years of the contract to compensate for the loss of profit in the initial years, B.C. Hydro must ensure the generation is maintained for the entire term. Premature plant retirement could be costly to B.C. Hydro. Compensation would likely be sought in such instances.

Conversely, private power producers' interest payments are greatest at the beginning of projects. To ensure revenue streams are sufficient to meet these requirements, some increase in early payments is likely appropriate. B.C. Hydro has generally limited front-end loading to that provided by a flat nominal payment schedule. Exceptions to this may be considered, however, where the curtailment risk is reduced. This could occur where a private power producer's investment extends beyond the assets associated with the generation project (eg. pulp and paper production facilities, mining equipment etc.).

B.C. Hydro is interested in reducing the risk associated with private power production through payment schedule design. Each project will be reviewed individually to determine the most appropriate schedule.


Real Dollar Payment Schedules
PV of Each = $1000
Annual Payment
$240
$200
$160
$120
$80
$40
1
2
3
4
5
6
7
8
9
10
Year
Schedule is front-end loaded if early payments > flat
Note low payments at end of front-end loaded schedule
Flat
Levelized
Front-end Loaded
Delayed Payment